UTILITY COAL-BIOMASS COFIRING TESTS

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Abstract

Biomass is an attractive renewable fuel to supplement coal combustion in utility boilers. Biomass includes a variety of wood and agricultural wastes such as sawdust, utility poles, pallets, tree trimmings, nut shells, or bark. These have a broad range of moisture contents (and, hence, heating values), size characteristics, bulk densities and ash chemical compositions. A supply curve developed in this paper shows that biomass cofiring is not likely to replace 3% of coal-based electricity in the U.S. Nevertheless, the use of biomass in coal-fired power generation represents a true source of renewable energy, with potential benefits such as CO_2 mitigation, fuel flexibility, lower fuel cost, improved local economies, lower emissions, and early entry by coal-fired power companies into renewable power generation. EPRI, with DOE cofunding through FETC and EERE, and with utility cooperation and cost sharing, has tested cofiring of biomass in ten (10) coal-fired utility boilers. The DOE/EPRI tests supplement the experience with biomass fuel in all major boiler types, including cyclones (crushed coal), wall- and corner-fired units (pulverized coal), fluidized beds, and a small industrial stoker (sized coal, crushed and without fines). A total of over 70 MW of biomass generating capacity has been tested in the DOE/EPRI program, cofired with coal at biomass input ranging from 1.5% to 10% of the total heat into the boilers. These cofiring tests have addressed many installation and operational issues for cofiring biomass. Preliminary results have shown that the cofiring of up to 7% biomass, on a heat-input basis, with crushed or pulverized coal can lower NOx emissions by as much as 15 percent depending on the firing configuration. These tests did not explore optimizing the firing configuration for biomass to maximize the NOx control potential for this renewable fuel. Some tests did not show any NOx reduction. Generally, the impact on boiler efficiency and load capacity is low and is primarily attributed to moisture in the biomass.

Because of the increased interest in biomass and pending legislation on the increased use of renewables in power generation (and, possibly, CO_2 mitigation), EPRI has formed the Biomass Interest Group (BIG). With DOE as the major cofunder, EPRI and utilities will participate in upcoming extended test programs that are intended to provide ongoing operations where visitors can witness cofiring firsthand and where the operators and managers of the power plants involved can improve technologies through hands-on experience.

BACKGROUND AND MOTIVATION

Biomass power generation reduces the net greenhouse gas emissions of CO_2 from power plants. Because of this, the Federal Energy Technology Center (FETC) of DOE, has joined with EPRI and several EPRI-member utilities to test the feasibility of cofiring biomass and other renewable waste fuels with coal for power generation. The FETC/EPRI program has thus far included ten full-sized tests of biomass cofiring, conducted in coal-fired boilers ranging in size from 15 to 500 MWe. (The 15 MW case was a stoker boiler, not utility-owned, and is not summarized in this paper.)

Biomass encompasses many types of wood byproducts and agricultural wastes. Wood byproducts include sawdust, bark, pallets, tree trimmings, cardboard, etc. Agricultural wastes include rice hulls and straw, walnut shells, etc., and, in the future, alfalfa and switchgrass. Wood wastes have long been used as supplemental fuels for industrial steam raising. More recently, however, utilities have investigated the use of these biomass fuels in order to reduce overall fuel costs, to generate some power from a renewable resource or as a potential way to reduce greenhouse emissions. When biomass is burned, the carbon emitted as CO_2 is recycled back into growing new trees or other crops at roughly the same rate (i.e., over tens of years, not millions of years), thus contributing a net zero loading to the existing CO_2 atmospheric inventory. Thus, the fossil fuel displaced by biomass represents a net reduction in the amount of new carbon being transferred to the atmosphere from geologic formations.

The potential benefits of biomass cofiring do not end at CO_2 emission reductions, however. Biomass can sometimes be a low-cost opportunity fuel source, providing fuel cost savings to the plant and, at the same time, helping local industries that seek low-cost/low-risk disposal of wastes or new markets for their wastes and byproducts. The environmental benefits of burning biomass in a controlled environment can also provide the utility with a way to gain or retain customers who desire to purchase "green" power. Finally, cofiring biomass can reduce emissions of regulated ("criteria") pollutants, specifically SO_2 and NOx. The potential mandates for Renewable Portfolio Standards (RPS), recently proposed in state and federal legislation, provide additional motivation for power generators to supplement fossil fuels with "green" renewable biomass.

POTENTIAL ROLE AND COSTS OF BIOMASS COFIRING ("SUPPLY CURVE")

Cofiring tests have shown that biomass can be readily burned along with coal in a variety of coal-fired utility boilers. Tests have also shown limits. A key limit is on the fraction of biomass that can be fed through the pulverizer in a pulverized coal (PC) plant: less than 4% by mass, which is 2% by heat. Using such test results combined with design/cost studies, EPRI has developed estimates of the potential near-term role of biomass cofiring in different types and sizes of utility boilers. The estimates were prepared using a two-round deployment scenario. Tables 1 and 2 display "Round No. 1," a projected first wave of biomass cofiring deployment. Later, Tables 3 and 4 display "Round 2," a second wave of additional or expanded deployment.

The first two columns of Table 1 give the label and the generating capacity in the USA for each of five categories of the major coal-fired boiler types that are candidates for biomass cofiring by electric utilities. The next four columns give (1) assumed average capacity factor, (2) resulting TWh of electricity generated, (3) assumed biomass cofiring level (% by heat) for that category, and (4) assumed fraction of market penetration. The last two columns show the calculated TWh of electricity from biomass, and the amount of biomass fuel required to generate that amount of electricity via cofiring. The results show that a total of 29.48 TWh (i.e., 29.48 billion kWh) of bioelectricity could be produced under this Round 1 scenario. This amount of electricity would require 18.87 million dry tons of biomass.
Table 2 continues from Table 1 to add a display of the costs and the amounts of CO_2 emission reductions (the "supply curve" or "CO_2 mitigation curve"). Table 2 shows that the first round deployment of biomass cofiring would reduce the fossil CO_2 emitted by coal-fired electrical generating plants by 26.7 Mtonne/yr. The total cost of cofiring of this amount of biomass in the U.S. is calculated to be $150 million. Cumulative costs can be used for comparison with other CO_2 mitigating options available to the electric

utility industry. Cost estimates were developed for the first three equipment categories (all of the cyclones, plus the large PCs) coal cost, a $0.53/MBtu biomass cost ($0.50/GJ), and a capital cost of $50/kW (for each kW of biomass capacity) to modify the plant for biomass cofiring. These three boiler equipment categories combine to yield 13.8 million tonnes (metric) of CO_2 reduction per year and consume 10 million dry tons (short tons) of biomass. For these three categories the net cost is negative. This is because of the assumed $0.72/MBtu differential price advantage of biomass over coal. For the two remaining boiler categories (medium and small PCs), the biomass fuel cost was assumed to be $0.96/MBtu, and the capital cost was increased from $50/kW to $200/kW or $230/kW (medium or small). <u>Coal cost was fixed at $1.25/MBtu, and capital costs were annualized at 33 percent per year</u>. For these smaller size boilers, there is a net incremental cost such that the cumulative cost for all five boiler categories totals $150 million per year. The associated reduction of 26.7 million metric tonnes of CO_2 translates to an overall average cost of $5.60/tonne CO_2. The cumulative 29.48 TWh generated from biomass instead of coal amounts to 1.48% of the assumed 1,992 TWh of coal-based electricity generation in the U.S.

Table 1. Potential cofiring market: Electricity generation and biomass use (Round 1 of deployment)

Boiler Equipment	Available Generating Capacity, GW	Average Capacity Factor, %	Available Annual Electricity Generation, TWh	Biomass Cofiring Level, %	Assumed Market Penetration, Fraction	Bio-Electricity Generation , TWh	Biomass Fuel Use, Mton/yr
Large Cyclones	12	0.82	86	2.5	0.70	1.51	0.95
Other Cyclones	11	0.78	75	5.0	0.70	2.63	1.85
Large PCs	220	0.73	1405	2.0	0.40	11.38	7.20
Medium PCs	60	0.66	347	10.0	0.30	10.41	6.52
Small PCs	15	0.60	79	15.0	0.30	3.55	2.35
Total (or Avg.)	318	0.72	1992	3.5	0.47	29.48	18.87

Table 2. Estimated cost of biomass cofiring – Round 1

		Biomas	Cumulative	Coal-based	CO_2 Reduction,		Capita	Total Cost	
					By	Cumul-		Incremental,	Cumulative,
A1	Large Cyclones	0.53	0.95	0.08	1.31	1.31	50	(2.3	(3)
B1	Other Cyclones	0.53	2.80	0.13	2.55	3.86	50	(2.7)	(11)
C1	Large PCs	0.53	10.0	0.57	9.90	13.8	50	(1.6)	(29)
D1	Medium PCs	0.96	16.52	0.53	9.56	23.3	200	11.9	94
E1	Small PCs	0.96	18.87	0.17	3.42	26.7	230	15.6	150
Total		-	-	1.48	26.7	-	-	-	-

Other key assumptions used in developing these cost estimates include:

Conversion from added electricity cost in $/MWh to the cost per unit of fossil CO_2 avoided in $/Mtonne is based on the amount and the properties of the coal being replaced by the biomass. EPRI assumed the following for all the cases: coal heat content 12,500 Btu/lb, as received; and, coal carbon 72.5% by weight of the as-received coal. For the coal heat rate of 10,000 Btu/kWh, which was assumed for the smaller cyclone and PC units, these assumptions results in 1 MWh of coal-fired electricity emits 1.103 short tons of fossil CO_2, almost exactly 1 tonne (metric) of CO_2. At better coal heat rates less CO_2 is produced per MWh: 0.95 tonne at 9500 and 0.90 at 9000.

Capital cost in $/kW is based on the biomass fraction of the generation, rather than on the total generating capacity of the unit on 100% coal. For example, a $200/kW cost for retrofit of a medium size 200 MW PC boiler during Round 1 deployment would translate to $20/kW for the assumed 10% cofiring level, or a total cost of $4M to modify the unit to cofire 10% biomass.

Low capital cost estimates of $40/kW and $50/kW were based on the simple biomass feed systems that blend biomass with coal and feed the blended fuels through the crusher (for cyclones) or pulverizer (for PCs).

Capital cost estimates of $175/kW, $200/kW and $230/kW were based on higher-cost retrofits that utilize separate biomass feed systems, i.e., that feed the biomass directly into the boiler through a separate injection port or ports with no blending with coal until the flames mix inside the boiler itself. In general, cyclone boilers are more adaptable than PC boilers to blended coal and biomass feed, because for cyclones the coal is crushed, rather than pulverized, and the fuel particle need not be as small. Blended fuel for a pulverized coal boiler requires that the biomass be fed through existing coal mills, and in this case the cofiring fraction will be limited (to about 2% of the heat input) by pulverizer performance: namely, throughput and coal size. For PC boilers, a separate feed system for biomass, although more expensive, has the advantages of avoiding any changes to the existing coal preparation and delivery system, and, even more important, of avoiding derate or carbon-in-ash caused by pulverizer performance limits. In general, separate firing has a capital cost estimated to be about four times that for a blended system, as measured in capital cost per unit of <u>biomass</u> power generating capacity.

Incremental operating costs were developed based on one full-time equivalent added employee to operate the biomass feed system during one shift. It is possible that for separate feed more added employees will be required in order to cover other shifts. This would add to the incremental operating cost. EPRI used $70,000/year for the fully-loaded cost of the one added employee.

Plant net heat rate for large cyclones and PCs was estimated at 9000 Btu/kWh. Medium PCs and smaller cyclone boilers were given a heat rate of 9500 Btu/kWh. Smaller PCs were assigned a heat rate of 10,000 Btu/kWh. Biomass heat rates were 17% higher than coal-only for 45%-moisture biomass (i.e., the $0.53/MBtu biomass fuel cases) and 10% higher than coal-only for 30%-moisture biomass (i.e., the $0.96/MBtu biomass fuel cases).

A "second round" of deployment of biomass cofiring could extend bioelectricity generation and related CO_2 reduction beyond levels shown in Tables 1 and 2. The assumptions and the economics for this second round of deployment are shown in Tables 3 and 4. Specifically, the large cyclone boilers could cofire 5% by heat, instead of 2.5%, thereby adding another 1.51 TWh of biomass electricity. In the next category, "All Other Cyclones," the cofiring level could be 8%, not the 5% used in Round 1, thereby adding another 1.50 TWh. In the "Large PC" group, the market penetration could advance from 0.40 to 0.60, thereby adding another 5.63 TWh. In the "Medium PC" category, the cofired fraction could be 15% of the heat instead of 10%, thereby adding another 5.20 TWh. The last category, "Small PC," could advance from a market penetration factor of 0.30 to one of 0.50, thereby adding another 2.37 TWh. The result is an added 16.2 TWh for all utility boiler categories. For the economic analysis in Round 2, EPRI assumed a delivered fuel cost of $0.96/MBtu for all the biomass fuel. The total supply of biomass at $0.96/MBtu was assumed to be 22 million dry tons, and of this 22 million tons, some 8.87 were committed to the Medium PC and Small PC categories in the "first round" (Tables 1 and 2), after the 10 million tons assumed for the $0.53/MBtu biomass fuel supply had been used up by the three lower-cost categories (Cyclones and Large PC). The supply limit, i.e., the 13.13 million dry tons still remaining of the 22 million tons at $0.96/MBtu delivered cost, was not a limiting factor for the Round 2 scenario.

Table 3. Potential cofiring market: Electricity generation and biomass use (Round 2 of deployment)

Boiler Equipment	Available Generating Capacity, GW	Average Capacity Factor, %	Available Annual Electricity Generation, TWh	Biomass Cofire Level, %	Changes in Market Penetration, Fraction	Bio-Electricity Generation , TWh	Biomass Fuel Use, Mton/yr
Large Cyclones	12	0.82	86	5.0	No change	1.51	0.90
Other Cyclones	11	0.78	75	8.0	No change	1.50	1.00
Large PCs	220	0.73	1405	2.0	+0.20	5.63	3.36
Medium PCs	60	0.66	347	15.0	No change	5.20	3.26
Small PCs	15	0.60	79	15.0	+0.20	2.37	1.67
Total (or Avg.)	318	0.72	1992	5.14	0.19	16.2	10.2

Table 4. Estimated cost of biomass cofiring – Round 2

Boiler Equipment		Biomass	Cumulative	Coal-based	CO_2 Reduction		Capital	Total Cost	
					By	Cumul-		Incremental,	Cumulative,
A2	Large Cyclones	0.96	0.90	0.07	1.32	1.32	40	0.76	1.0
B2	Other Cyclones	0.96	1.90	0.08	1.45	2.77	40	0.80	2.0
C2	Large PCs	0.96	5.26	0.28	4.90	7.67	50	2.32	15
D2	Medium PCs	0.96	8.52	0.26	4.77	12.4	175	10.0	67
E2	Small PCs	0.96	10.2	0.12	2.34	14.7	230	16.3	105
	Total		10.2	0.81	14.7	-	-	-	-

Finally, Table 5 presents the combination of Tables 2 and 4 into an integrated total supply curve for CO_2 mitigation via biomass cofiring. The grand total is 45.7 TWh of biomass cofired electricity, which is 2.29% of the assumed 1992 TWh of today's coal-fired power generation in the USA. As shown in Table 5, the cumulative cost is $256 million to eliminate 41.8 million tonnes (metric) of fossil CO_2 emissions, or an average cost of $6.17 per metric tonne of CO_2, which converts to $22.62/tonne of fossil carbon emitted as CO_2. As can be seen in Tables 2, 4 and 5, cofiring in cyclones and large PCs yields savings. But for the high cost category, $55 million is needed to get the last 3.42 million tons of CO_2. This puts the marginal cost for the last increment at $16.08/tonne CO_2, or $58.97/tonne C.

Table 5. Supply curve for biomass cofiring – Rounds 1 and 2 of deployment, integrated and listed in order of increasing incremental cost

	B1 All Other	A1 Large	C1 Large PCs	A2 Large	B2 All Other	C2 Large PCs	D2 Medium	D1 Medium	E1 Small PCs	E2 Small PCs
Assumed Average Unit Size on Coal, MWe	250	500	500	500	250	500	200	200	100	100
Assumed Cofiring Level (i.e., fraction of heat from biomass)	5.0%	2.5%	2.0%	5.0%	8.0%	2.0%	15%	10%	15%	15%
Capital Cost, $/kW (per kW from biomass)	$50	$50	$50	$40	$40	$50	$175	$200	$230	$230
Separate Feed for Biomass	No	No	No	No	No	No	Yes	Yes	Yes	Yes
Delivered Biomass Cost, $/MBtu	$0.53	$0.53	$0.53	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96
Incremental Cost above 100% Coal, $/MWh	($2.70)	($2.26)	($1.62)	$0.76	$0.80	$2.32	$10.01	$11.86	$15.58	$16.25
CO_2 Reduction, Mtonne/yr (metric)	2.55	1.31	9.90	1.32	1.45	4.90	4.77	9.56	3.42	2.30
Cumulative Biomass Use, Mton/yr (short tons, dry basis)	1.85	2.81	10.01	10.91	11.90	15.26	18.52	25.04	27.39	29.06
Cumulative Bio-Electricity Generation, TWh/year	2.63	4.14	15.52	17.03	18.53	24.16	29.36	39.77	43.32	45.69
Cumulative Coal-based Generation Displaced (% of 1,992 TWh/yr)	0.13%	0.21%	0.78%	0.85%	0.93%	1.21%	1.47%	2.00%	2.17%	2.29%
Cumulative CO_2 Reduction, Mtonne/yr (metric)	2.54	3.86	13.76	15.07	16.52	21.42	26.20	35.76	39.18	41.48
Cumulative Cost, $M/yr (excess above 100% coal)	($7)	($11)	($29)	($28)	($27)	($14)	$39	$162	$217	$256

TEST RESULTS

Table 6 lists six sites where cofiring tests were recently performed under the DOE-FETC collaboration with EPRI and electric utilities. Over 70 MW of biomass-based capacity is listed. The boilers include all major firing types of utility boiler (wall, tangential, and cyclone), ranging in size from 32 to 425 MW. Beyond the FETC/EPRI program, additional cofiring tests have taken place during the past ten years, but are not reported here. These other tests include the following:

Northern States Power – King Station (Cyclone), ~ on all 500 MW
Tacoma Utilities – Steam Plant No. 2 (Fluidized Bed), 40 MW
Santee Cooper – Plant Jeffries (Pulverized Coal), 180 MW
Georgia Power – Plant Hammond (Pulverized Coal), ~150 MW
Georgia Power – Plant Yates (Pulverized Coal), ~150 MW
Savannah Electric – Plant Kraft (Pulverized Coal), ~59 MW
*GPU Genco – Shawville, PA (Pulverized Coal), ~160 MW
*University of Pittsburgh – Iron City Brewery in Pittsburgh, PA (Stoker), ~15 MW

*The starred (*) plants are actually included in the collaborative EPRI/DOE program, but are not among those summarized in this paper.

Table 6. Tests sponsored by utilities, DOE and EPRI within the DOE/EPRI program

Utility and Plant	Boiler Capacity and Type, MWe (Firing 100% Coal)	Biomass Heat Input	Biomass, MW	Biomass Type	Average Biomass Moisture	Range of Biomass Moisture
TVA Allen	272, Cyclone	10%	27	Sawdust	44%	14-48%
TVA Colbert	190, Wall-Fired	1.5%	3	Sawdust	44%	30-50%
NYSEG Greenidge	108, Tangential	10%	10	Wood	30%	20-50%
GPU Seward	32, Wall-Fired	10%	3	Sawdust	44%	10-52%
MG&E Blount St.	50, Wall-Fired	10%	5	Switchgrass	10%	8-13%
NIPSCO Mich. City	425, Cyclone	6.5%	28	Urban Wood Waste	30%	15-45%

The cofired fuel for the test sites listed in Table 6 was waste wood, except for MG&E Blount St. and one test of shrub willow energy crop fuel at NYSEG Greenidge. A key difference among the tests is the mode of biomass feed to the boiler, introduced in the boiler either separately from coal (separate feed) or in combination (blended feed, which flows biomass with the coal through the existing coal feed system of pulverizers for PC boilers, or crushers, for cyclone boilers). Typically, separate feed systems allow the coal pulverizers, used for wall-fired and corner-fired (tangential) units, to operate at reduced load, thereby assuring full capacity, but at higher capital cost for the modifications to the plant. The level of cofiring for these tests ranged from 1.5 to 10 percent on a heat input basis. Moisture level for the biomass ranged from 10 percent for the switchgrass to 52 percent for the highest moisture sawdust.
Some wood wastes were successfully cofired at about 50% moisture (GPU Seward and TVA Allen). Other physical and chemical properties for some of the waste fuels tested are summarized in Table 7.

Table 7. Some typical ranges of wood waste biomass fuel properties compared to coals and tire-derived fuel

Fuel	Btu/lb(1)	Fuel N(2)	Moisture(2)	Ash(2)	V/FC(3)	H/C(3)	O/C(3)
Wood Biomass	4,100 to 6,500	0.15 to 0.24	14 to 48	0.37 to 7.8	5.1 to 6.5	1.2 to 1.4	0.57 to 0.62
Eastern Coal	12,305	1.0	8.8	8.3	0.67	0.81	0.07
Western Coal	12,029	0.96	9.6	7.3	0.89	0.87	0.11
TDF	15,330	0.35	3.0	3.0	1.9	1.0	0.01

(1) As fired (2) Percent weight basis (3) Atomic ratio

Several performance measures were obtained at these sites, including output achieved, emission reductions and boiler efficiency. Typically, SO_2, NOx, and fossil CO_2 are the emissions impacted by biomass cofiring. SO_2 and CO_2 reductions achieved with cofiring are directly related to the quantity and chemical contents of the coal displaced by biomass. (The CO_2 reduction is <u>fossil</u> CO_2 reduction. Biomass combustion emits CO_2 but the CO_2 from biomass comes from carbon already in the atmosphere before being fixed in the living plant that is the source of the fuel being burned. The CO_2 from coal, or oil or gas, is carbon that was previously locked in various geologic formations within the earth.) The impact on NOx is more difficult to predict but is equally important, because of regulatory implications and potential cost savings or emission trade-off value greater that that of SO_2. Biomass has a much higher volatile content compared to virtually all coals. Thus, biomass cofiring has some potential to increase overall boiler combustion efficiency by reducing levels of unburned carbon in the ash and reducing the amount of excess air required. However, these two potential efficiency benefits are usually more than offset by the effects of the higher moisture level in the biomass, and the net result is a boiler efficiency that is lower, but only very slightly, compared to 100% coal combustion.

NOx emissions recorded at these cofiring sites are summarized in Table 8. Typically, the observed trend is for lower NOx emissions with increased levels of biomass cofiring, at least up to the point where about 10% of the heat is being supplied by the biomass. The recorded range of NOx reductions is typically between 0 and 15-20 percent. NOx reductions can be the result of several factors, including reduced total fuel nitrogen, lower firing temperatures because of increased fuel moisture, and increased staging of the combustion process due to early volatiles burnout in the biomass fraction. Preliminary results have shown that the cofiring of up to 7% biomass, on a heat-input basis, with crushed or pulverized coal can lower NOx emissions by as much as 15 percent depending on the firing configuration. These tests did <u>not</u> explore optimizing the firing configuration for biomass to maximize the NOx control potential for this renewable fuel, and some tests did not show any NOx reduction at all.

Results on efficiency and levels of LOI (i.e., carbon in the ash) showed that biomass cofiring is typically associated with a loss of some 0.3 to 0.6 points, out of about 85 to 88 percentage points, in overall boiler efficiency, when the cofiring is in the range tested, i.e., 4% to 10% of the heat input. Moisture in the biomass fuel accounts for the decrease in boiler efficiency. Unburned carbon effects were masked by changes in boiler operating conditions. Generally, there was no net change in boiler load capacity, although additional test data from longer-term test runs are needed to validate these early results from test runs that were typically of 3 to 6 hours duration.

Table 8. NOx emissions results with wood waste cofiring

Site	Biofuel	Baseline NOx lb/MMBtu	Percent Cofire (mass basis)	Percent Cofire (heat basis)	NOx Reductions (percent)
GPU Seward	Wood (FGS, DSS, and OS)[1]	0.87 to 0.95	3.4 to 6.4 8.2 to 9.4 11.9 to 13.8 16.1 to 17.9	1.5 to 2.8 3.1 to 4.3 4.3 to 8.1 7.6 10.3	0 to 11 2.3to 13 3.4to 14 5.7 to 18
TVA Allen	Wood (sawdust)	2.0 with E. Coal	8.5 to 10 20	4.5 9.0	0 to 11.6 25
TVA Allen	Wood (sawdust & woodchips	1.5 with W. Coal	4.3 10 15	1.9 4.7 6.9	-1.3 to 7.3 -8.7 to 14 -2.7
NIPSCO Mich. City	Wood	1.05 to 1.28 (1.17 avg.)	10	6.5	0 to 20 (9.5 avg.)

(1) FGS = Fresh Green Sawdust; DSS = Dry Shavings and Sawdust; OS = Old Sawdust.

FUTURE COMMERCIAL OPPORTUNITIES AND RESEARCH PLANS

Plans are currently underway for long-term continuous cofiring tests at selected sites. The DOE’s Office of Energy Efficiency and Renewable Energy (EERE) is joining the DOE Fossil Energy (FE) FETC/EPRI/industry cooperative effort. The EERE cofunding makes these long-term tests possible. The list of planned test sites is presented in Table 9. These tests are designed to meet the following objectives:

Provide host sites for evaluation by other owners/operators who are considering cofiring of biomass with coal. These host sites will provide valuable information on retrofit design and on how the designs work in routine operation.

Improve the technologies themselves, as ongoing experience leads to changes introduced by the operators and other staff who conduct and analyze the operations.

The GPU Seward project will build a permanent wood receiving, handling, storage, and feeding system at the Seward station about 15 miles northwest of Johnstown, PA. The system will be capable of receiving, screening (for size), stock-out, reclaim, metering, storage, and pneumatic injection into the boiler. This system is sized large enough to supply 7% of the heat to a 150 MW boiler, although the immediate use will be at the smaller 32 MW Boiler No. 12, where a baseline from the 1996-97 tests and an initial low-cost biomass fuel supply are available for the initial 18 months of operation. At 32 MW, the boiler is small, thereby facilitating measurement and operation, but is of the most common design: wall-fired pulverized coal (PC). The sawdust-sized fuel will be injected down the unused center pipe of three of the six pulverized coal burners and will be directed out into each of those three coal flames by a diffuser at the end of each center pipe. The preparation (i.e., “grinding” or size reduction) of utility poles and cross bars as fuel is planned for later in the initial 18 months, as a test of routine fuel preparation and cofiring combustion operations on treated wood. Such fuel, i.e., treated wood, could become a zero-cost or negative-cost fuel (i.e., where the power plant, or the woodfuel provider to the power plant, receives a fee for disposal of wood wastes).

Table 9. Cofiring tests planned for 1998-2000 under the DOE/EPRI program

Utility and Plant (and type of coal feed)	Boiler Capacity and Type	Biomass Heat Input	Biomass Type	Biomass Feed System
NIPSCO Bailly	160 MW	5%	Wood and Pet. Coke	Blended (with coal, thru
TVA Allen	270 MW	>10%	Biomass (low-cost	Separate feed (gas, instead
GPU Seward	32 MW	>10%	Sawdust (including	Separate feed
NYSEG Greenidge (PC)	100 MW	10%	Wood (including some	Separate feed
Southern Co. (Alabama	60 MW	4%	Switchgrass	Blended (with coal, thru

The tests at the NIPSCO Bailly plant will consist of "tri-firing" crushed coal with petroleum coke and wood waste. The demonstration will provide important data on the "synergy" among the two waste fuels cofired in combination with crushed coal in the cyclone boiler. The synergy is expected because the wood will provide a volatile fraction that the petroleum coke is missing, thus promoting more complete combustion and, perhaps, NOx reducing. Also, the lack of sulfur in the wood will offset the higher sulfur content of the coke. On the other side of the synergy, the high heat content and high mass density of the pet coke will provide a "Btu kick" to the low energy density of the biomass fuel. Finally, the low cost of the petroleum coke will offset the cost of the wood waste, thereby providing an overall low-cost blend of cofired fuel.

The planned tests at the TVA Allen Fossil Plant will prove key technical and economic data on the use of biomass gasifier offgas as the fuel that is actually cofired with coal in the boiler. The process involves the use of a separate unit to gasify the biomass and the feeding of the resulting gaseous fuel to the boiler via new or modified gas burners and ports. The use of gasifier offgas cofired in utility boilers may offer potential advantages over direct biomass cofiring because:

No additional ash is introduced into the boiler, and, therefore, the quality of the ash and its sale are not impacted. (And, ash deposition, if any, may be mitigated.)

The boiler operation is not directly dependent on the quality of the biomass fuel, thus increasing the potential to use low-cost opportunity fuels.

Mild atmospheric gasification, without gas cleanup/conditioning to meet gas turbine fuel inlet standards, is a low capital cost and low operating cost approach to energy recovery from biofuels, when compared to biomass gasification plus gas conditioning for a gas turbine cycle or a gas engine.

BIOMASS INTEREST GROUP

Because of the specialized utility interest in biomass cofiring and the desire of some EPRI funders to be prepared for pending legislation to increase the use of renewables in power generation (and, possibly, fossil CO_2 mitigation), EPRI has formed the Biomass Interest Group (BIG). Members of BIG are either actively involved in biomass fuel testing/evaluation or are considering such for the future. The group provides DOE, utilities and power companies a forum for technology transfer and for leveraging research funds that address the important technical, economic, and institutional issues associated with issues such as the following: resource and supply, cofiring, fuel preparation, direct firing, gasification, environmental benefits, performance, costs, and marketing. With DOE as the major cofunder, EPRI and utilities will participate in upcoming extended test programs that are intended to provide ongoing operations where visitors can witness cofiring firsthand and where the operators and managers of the power plants involved can improve the technology through hands-on experience.

CONCLUSIONS

The DOE-FETC/EPRI test program so far has confirmed the technical feasibility of biomass cofiring and has documented performance and the potential for some benefits, such as lower NOx emissions (versus 100% coal) and lower costs of power generation (versus those of most renewable energy options and many CO_2 capture/sequestration options). Ongoing and planned research will target continued progress on these and other technical and economic issues. Key issues include:

Influence of cofiring on boiler efficiency and load capacity. This would identify operational changes that might mitigate potential losses in boiler efficiency and loss of load capacity due to wet and lower-Btu fuel.

Influence on flyash properties and potential effect on ash sales. Tests to date point to minimal impact of cofiring on ash quality and on other technical issues that affect marketability of ash. However, an important, and current, ASTM standard has long required that ash used in cement manufacturing be from <u>coal only</u>.

- Impact on boiler slagging and fouling patterns, and the extent of any associated maintenance requirements. These are not expected to be issues for clean wood wastes, but could be issues in cofiring straw, grass, chicken litter or other high-alkali or high-chlorine biomass.
- Development of storage and fuel-preparation guidelines for specific boiler applications.
- Development of concepts that can reduce capital and operating costs.
- Maximizing the potential for NOx reductions.
- Level of biomass cofiring (i.e., the fraction of biomass fired with the coal) that is conducive to optimum and cost-effective operation, for example, pushing for 15% by heat.

On all of these issues, the most important advances will be (1) data coming from long-term, on-going operations, and (2) improved technology arising from improvements discovered by the operating and managing staff as a result of their hands-on experience.

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